CHAPTER 6: The California Power Sector

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California offers an instructive case study of electric industry restructuring for a variety of reasons. California has been a leader, not only in electricity market reform efforts in the US, but also worldwide. It was in California that the development of an independent power industry began in the early 1980s. More recently, California was also among the first US states to open its market to retail competition and to develop an open wholesale electricity market with both an hourly spot market and a transmission/system operator. California has the longest and most detailed experience with competitive electricity markets in the US.

Additionally, beginning during the summer of 2000, an electricity crisis gripped the state, resulting in periodic blackout conditions, unprecedented wholesale electricity prices, and a financial catastrophe for the state's electric utilities. Out of this crisis is emerging a new structure for the electricity sector in the state, one that may look far different from the one envisioned at the onset of the state's restructuring process. The impacts of the crisis have been profound. Analysts and politicians the world over have used California's electricity restructuring experience to rethink the basic tenets of electricity reform, and to reconsider the previously inexorable trend towards increasingly open wholesale and retail electricity markets. At the very least, the problems experienced in California call for a rethinking of the design and regulation of competitive electricity markets.

The majority of this case study focuses on the design and structure of California's restructured electricity industry prior to the crisis. The case study begins with a general overview and description of California's power system. The regulatory framework that has shaped the structure of California's electricity sector, pre- and post-reform, is then described. The design of California's new wholesale electricity market is highlighted, as are transmission issues, distribution network regulation and retail competition. Other aspects of California's restructured electric system are also discussed. The case study concludes with a discussion of early experience with electricity sector reform in California, the nature of the state's electricity crisis, its causes, and its possible impacts on the design of California's future electricity system.

1. General Description of the California Power System

In late 1996, the California state legislature approved legislation that fundamentally reorganized the state's electricity industry and introduced retail competition for California's electricity consumers starting March 31, 1998. To understand these and related changes in California's electricity sector it is important to begin by understanding the basic structure of the electricity system in the state.

More than 3,000 electric utilities operate in the US to provide electricity service to customers. At the end of 1999, the *net* generating capacity of the US electric power industry stood at more than 779 gigawatts (GW) (EIA 1999a). (Net generation excludes self-generation units and internal generation uses.) Sales to ultimate customers in 1998 exceeded 3,240 terawatt-hours (TWh) at a total cost of more than $218 billion (EIA 1999a). Though most of the utilities in the US are publicly- or cooperatively-owned, sales by the 239 private, investor-owned utilities represent approximately 75% of total electricity sales (EIA 1999b).

As the US state with the largest population, generation serving California load represents approximately 7% of total generation in the US (EIA 1998). Before the restructuring of the industry in 1998, California's electric industry consisted of both public and private vertically-integrated electric utilities that managed and operated the bulk of the generation, transmission, and distribution systems in the state. The three largest private, investor-owned utilities (IOUs) are Pacific Gas and Electric Company (PG&E), Southern California Edison (SCE), and San Diego Gas and Electric Company (SDG&E). These three utilities combined have historically served approximately 75% of all load in California. The remainder of the load has been served by a mix of more than 40 smaller investor-owned, publicly-owned, and cooperative utilities, the largest of which are the Los Angeles Department of Water and Power (LADWP) and the Sacramento Municipal Utility District (SMUD).

California's IOUs are regulated by the California Public Utilities Commission (CPUC), which has historically overseen utility rates and operations, by the California Energy Commission (CEC), which oversees new plant siting and construction, and by the Federal Energy Regulatory Commission (FERC), which regulates wholesale electricity trade and inter-state transmission. Publicly and cooperatively owned utilities are regulated by municipal, county, and/or other applicable oversight bodies, subject to state and federal law.

Each of the main IOUs were, historically, responsible for matching load and resources to maintain electrical reliability and to match scheduled and actual flows at tie points by which the utilities are connected to other power producers. Each of the utilities, having an obligation to serve load within its service territory, developed its own generation and demand forecasts, operated generating plants, and entered into procurement contracts for the fuel used to generate electricity. Each utility also participated in short- and long-term bilateral contracts for electric power.

1.1. Generation

Within California, electricity is generated by more than 1,300 power plants. Total electric generation serving California in 1999 was 259 TWh (including self-generation). Importantly, historically about 20% of the electricity used in California has been met with power imported from neighboring US states (approximately half of which is coal and the other half hydro).

Until the late 1970s, virtually all of the electric generating capacity in California was owned by electric utilities and government agencies. Since the late 1970s, however, wholesale competition in electricity generation has been allowed (as discussed in Section 2, below) and a significant fraction of the total generation serving California load now comes from independent, non-utility generators selling to California utilities. For example, in 1996 before electricity restructuring, 81% of California's generating capacity was utility owned, with the remaining 19% owned by non-utility generators. After the utility divestiture of generation beginning in 1998 and stimulated by electricity reform, utility ownership dropped to 46% of the total, compared to 54% for non-utility generators. Most of the non-utility owned generation comes from natural gas and renewable energy.

Table 6.1 presents the resource composition of the total electric generation serving California, including in-state electricity generation and imports. As can be seen in the table, California's electricity supply is diverse, with substantial amounts of gas, hydropower, coal, nuclear, and renewable energy generation.

Table 6.1. Electricity Production by Generation Resource (including imports), 1999

Resource	**Energy**
Hydroelectric	20.1%
Nuclear	16.2%
Coal	19.8%
Gas and Oil	31.0%
Renewables and Other	12.2%
TOTAL	259 TWh

Source: www. energy.ca.gov/electricity/system_power.html

1.2. Transmission and Interconnections

The electric utilities in California are electrically linked through an extensive network of transmission lines. In California, the main transmission grid consists of 500 kV, some 230 kV, and 500 kV DC high-voltage transmission lines. Some larger customers receive service at these high voltage levels. For smaller customers, the voltage is stepped down to lower voltages (for example, 120 volts for residential customers).

The main three investor-owned utilities, PG&E, SCE, and SDG&E, have historically owned and operated the bulk of the transmission grid in California (some of the smaller utilities also own pieces of the transmission system). These same utilities also served as managers of the coordinated operation of the generation and transmission systems (economic and technical functions, such as security analysis, economic dispatch, unit commitment, etc.). Under restructuring, these IOUs were to maintain ownership of their transmission assets and responsibility for maintenance. But as discussed in more detail below, an Independent System Operator (ISO) was created to operate the bulk of the transmission system in the state. Finally, as a result of the deepening electricity crisis, the state government in early 2001 began to negotiate with the utilities for the ownership the IOUs' transmission systems.

The state of California also has numerous transmission interconnections with adjacent states. This allows for power transfers from throughout the Western US interconnected system. The most important of these interconnections are those to the Northwest and Southwest, where a significant amount of electricity trade takes place. Of the 20% of electricity that came from imports into the state in 1998, the CEC estimates that 48% came from the Northwest and 52% from the Southwest interconnections.

1.3. Distribution

Distribution power lines generally include line voltages at and below 50 kV. The distribution networks in California have and continue to be owned and operated by the various utilities in the state, including the three large IOUs, as well as the smaller investor-owned and the publicly-owned utilities. Under restructuring, these companies are continuing to provide distribution services to all electric customers within their respective service territories.

1.4. Consumption

Table 6.2 shows the electricity consumption and number of customers in each customer class in California. Of the total electricity consumed in California in 1998, Table 6.3 shows the breakdown by utility service territory. In total, 72% of total consumption comes from investor-owned utilities and 28% from publicly-owned utilities.

Table 6.2. Electricity Consumption and Number of Customers in California, 1998

Customer Class	Number of Customers	Consumption (TWh)
Residential	11,331,398	75
Commercial	1,522,665	86
Industrial	39,902	59
Other	47,000	7
TOTAL	12,885,000	226

Source: EIA (1999c)

Table 6.3. Electricity Consumption by Utility Service Territory, 1998

Utility	Consumption (TWh)	Percent of Total
Southern California Edison	76.3	33.8%
Pacific Gas & Electric	75.7	33.5%
Los Angeles Department of Water & Power	21.7	9.6%
San Diego Gas & Electric	16.3	7.2%
Sacramento Municipal Utility District	9.1	4.0%
Other	26.9	11.9%
TOTAL	226	100%

Source: www.eia.doe.gov /cneaf/electricity/esr/t17a.txt

1.5. Concentration Levels

As of early 2001, the large IOUs continue to own the bulk of the transmission and distribution network in California. Though retail competition has allowed customers to select alternate energy service providers, as a practical matter the majority of load that has been eligible for retail competition has remained with the incumbent utilities. As a result of the electricity reform process, the three major IOUs were required to temporarily sell into and purchase from a centralized power exchange in part to reduce the potential for the abuse of horizontal market power, and the ISO was created to reduce the likelihood of vertical market power. To reduce concentration levels in electricity generation, the three major IOUs have completed the sale of, or are in negotiation to sell, all their California *thermal* generation assets as well as some other generating plants. As discussed later with respect to the energy crisis in California, however, even these mitigation measures have been inadequate in protecting California’s electricity system from the abuse of market power.

1.6. Plant Investment

Based on information provided to the Energy Information Administration (EIA), total plant investment by investor-owned utilities in the US can be broken down as listed in Table 6.4. As shown in this table, most of the plant investment comes from electricity production and distribution.

Table 6.4. Net Electric Utility Plant Investment in the US, 1996

Investment Type	Percent of Total Investment
Electricity Production	54.6%
Transmission	11.6%
Distribution	28.8%
Other	5.0%

Source: EIA (1997)

1.7. Electricity Prices

California's 1998 electricity rates, by customer class, are shown in Table 6.5 and compared to US average rates. Rates in California are clearly higher than the national average, a key driver in the state's restructuring efforts. Moreover, the year 2001 ushered in significant increases in these already high rates as a response to the energy crisis.

Table 6.5. Electricity Rates in California and the US (¢/kWh), 1998

Customer Class	California Electricity Rates	US Average Electricity Rates
Residential	10.5	8.3
Commercial	9.7	7.4
Industrial	6.3	4.5
Other	7.5	6.8
AVERAGE	9.0	6.8

Source: EIA (1999d)

2. The New Regulatory Framework

While California was one of the first US states to inject competition into its electricity market, many of the changes enacted in the state have emerged out of a series of broader regulatory changes at the national level. In the US, the federal government regulates *interstate* commercial transactions and the states have authority to regulate *intrastate* commerce. In the electricity industry, this division of regulatory power has typically meant that the federal government (through the Federal Energy Regulatory Commission, or FERC) has overseen wholesale electricity transactions and issues related to transmission pricing and access. The state commissions (frequently termed public utility, public service, or corporation commissions) have regulated retail electricity transactions and access to the distribution grid. To better understand California's new market structure and regulatory system, it is necessary to first introduce key federal legislation and regulations.

2.1. US Federal Legislation and Regulation

2.1.1. Public Utility Holding Company Act of 1935

The current structure the US electric power industry was established with the passage of the Public Utility Holding Company Act (PUHCA) in 1935. PUHCA was aimed at breaking up the large and essentially unconstrained holding companies that then controlled much of the country's electric and gas distribution networks. Under the Act, the Securities and Exchange Commission (SEC) was given the power to break up interstate utility holding companies by requiring them to divest their holdings until each became a single consolidated system serving a circumscribed geographic area. The law further required electricity companies to engage only in business activity essential and appropriate for the operation of a single, vertically integrated utility. This latter restriction essentially eliminated the participation of non-utilities in wholesale electric power sales. PUHCA also required that any utility engaging in interstate electricity trading or transmission be regulated by the Federal Power Commission, which, in 1977, became the FERC (EIA 1993, 1996).

2.1.2. Public Utility Regulatory Policies Act of 1978

The landscape created by PUCHA remained largely intact until 1978 when, spurred by increased concern about US dependence on foreign oil in the wake of the OPEC oil embargo, as well as by an increased environmental awareness, the US Congress passed the Public Utility Regulatory Policies Act (PURPA). Designed to promote energy efficiency and increase the amount of cogeneration and renewably generated energy, PURPA was significant for the utility industry because it ensured a market for non-utility generated electricity.

PURPA established a new category of independent electricity generators called "qualifying facilities" (QFs) that were defined as non-utility power wholesalers that were either (1) cogenerators, or (2) small power producers utilizing specified renewable energy resources. (Eligible renewable resources included biomass, waste, geothermal, solar, wind, and hydroelectric power under 30 MW in size.) Under the law utilities were required to purchase whatever amount of electricity was offered from any facility meeting the QF criteria at a rate equal to the purchasing utility's incremental or avoided cost of production (PURPA 1978, EIA 1996, Watkiss and Smith 1993). Though competitive bidding has been used to set avoided cost payments in recent years, many of the early QF contracts were set at high, fixed avoided cost levels. (This is discussed further in the section on stranded cost issues.) PURPA served as a first step in opening up the wholesale electricity market to competition and allowing participation in that market by non-utility entities.

2.1.3. Energy Policy Act of 1992

The introduction of wholesale competition was furthered with the passage of the Energy Policy Act (EPAct) in 1992. As with PURPA, concern about America's oil dependence--this time in light of the 1991 war with Iraq--was a key driver of a range of new energy regulations outlined in EPAct. Provisions dealing with the utility industry were also driven by increased awareness of the benefits of new, more decentralized generation technologies, and by an increased sense in academic and policy circles that economic efficiency gains could be realized by the introduction of competition in areas once thought the province of regulated monopolies (Joskow and Schmalensee 1983, Kahn 1988, Hausker 1993, Watkiss and Smith 1993).

In brief, EPAct substantially reformed PUHCA and made it easier for a broader array of non-utility generators to enter the wholesale electricity market by exempting them from PUHCA constraints. The law made these changes by creating a new category of power producers called exempt wholesale generators (EWGs). EWGs differ from PURPA QFs in two ways. First, EWGs are not required to meet PURPA's cogeneration or renewable fuels limitations. Second, utilities are not required to purchase power from EWGs. Instead, marketing of EWG power is facilitated by provisions in EPAct that give FERC the authority to order utilities to provide access to their transmission systems on non-discriminatory terms. Specifically, EPAct instructs FERC to require utilities (see EPAct 1992, Hausker 1993, Watkiss and Smith 1993, EIA 1996) to make transmission service available at "just and reasonable" rates, designed to cover all "legitimate, verifiable, and economic costs," subject to the condition that any incremental costs be recovered from the entity seeking transmission service and not from the transmitting utilities' existing customers.

These transmission provisions have effectively paved the way for open-access wholesale electricity transactions on a nation-wide basis. This new market has been especially significant for smaller, transmission-constrained utilities that are no longer dependent on adjacent utilities for wholesale power. Yet while EPAct established a legal framework for widespread wholesale competition, the specifics of the wholesale market were laid out later in FERC Orders 888 and 889.

2.1.4. FERC Orders 888 and 889

Following the direction and guidelines spelled out for it in EPAct, the FERC began to review and mandate wholesale transmission requests on a case by case basis beginning in 1993. (FERC's first ruling mandating wholesale transmission access came in October 1993 in *Florida Municipal Power Agency v. Florida Power & Light Co.*) While hearing case by case requests, however, FERC was also looking for a more comprehensive way to mandate terms for open-access wholesale electricity transactions.

After issuing an initial set of proposals in a document known as the "Mega-NOPR" and taking comments, the FERC released two major final rules on transmission access in Spring 1996. (NOPR stands for "notice of proposed rulemaking.") These rules, termed Orders 888 and 889, spelled out the specific details and requirements for wholesale electricity transactions and established a real-time transparent trading communications system. In brief, Order 888:

- Requires all utilities under FERC jurisdiction to file nondiscriminatory open access transmission tariffs, available to all wholesale buyers and sellers of electricity.
- Requires utilities to take service under their filed tariff rates for their own wholesale electricity purchases and sales.
- Allows utilities to recover all legitimate, prudent, and verifiable but now uneconomic (i.e., "stranded") wholesale costs and investments incurred before July 1994. (We discuss stranded costs—a key issue in the US debate over utility industry restructuring—in Section 6.)

The first two of these provisions enable all electricity providers to have access to the transmission grid on equal terms for both point-to-point and network transmission services, including ancillary services. The final provision recognized the legitimacy of utility concerns regarding the recovery of sunk costs incurred under a different regulatory regime and with different expectations about the likelihood of cost recovery. Finally, Order 888 required that municipal and other utilities not under FERC jurisdiction nonetheless provide reciprocity should they wish to avail themselves of the open access tariffs offered by utilities complying with the FERC order. In other words, the reciprocity rule ensures that if a municipal utility wanted to purchase transmission service from an IOU under the terms of Order 888, they must offer service on similar terms (FERC 1996a, EIA 1996).

On the same day it issued Order 888 FERC also issued Order 889, which compelled utilities to create and use an open access same-time information system (OASIS) providing all open access transmission customers with standardized electronic information on transmission capacity, prices, and other essential market information. The rule also requires that transmission operations personnel at utilities function independently of generation and wholesale trading personnel. Finally, while not mandating the creation of independent system operators (ISOs), Order 889 encourages the creation of ISOs and recognizes that they would fall under FERC's jurisdiction (FERC 1996b, EIA 1996). Subsequent orders have clarified FERC's position on the formation, design, and governance of regional transmission organizations and ISOs.

2.2. California State Legislation and Regulation

2.2.1. California Public Utilities Commission Activity

As federal legislation and regulations began to restructure the US electricity industry nationally, regulatory officials in California started to investigate the possibility of implementing even more sweeping changes. In the early 1990s the California Public Utility Commission (CPUC) began to explore the possibility of introducing some form of retail competition within the state's three investor-owned and CPUC-regulated utilities.

At the time California was beginning to emerge from an economic recession and the state's electricity prices were more than 40% higher than the national average—even for industrial customers—and as much as double those of neighboring states (EIA 1995). Concerned about the loss of industrial businesses seeking cheaper electric rates and aware of successful deregulation and cost savings in other industries, the CPUC issued its "Yellow Paper" in February 1993 detailing options for introducing retail competition for electricity service (Fessler 1997, CPUC 1993). In addition to competitiveness concerns and deregulation experience in other industries, drivers behind the move towards retail competition in California also included an increased perception of the inefficiencies of traditional "command and control" regulation, a desire to tap new and potentially more cost effective generation technologies, and advances in communications and information technologies necessary for price discovery and the unbundling of various electricity-related services (Joskow and Schmalensee 1983, EIA 1996, Pickle, Marnay, and Olken 1996).

In April 1994 the CPUC released a follow-up document called the "Blue Book." The Blue Book advanced a more detailed proposal for retail competition in the service territories of the three major California IOUs. Specifically, the Blue Book called for (see CPUC 1994, Blumstein and Bushnell 1994):

- the introduction of a comprehensive wholesale spot market trading system (e.g., UK-style "poolco");
- the introduction of (1) a non-bypassable competition transition charge (CTC) designed to facilitate the recovery of utility stranded cost and (2) another similar but much smaller charge to fund public purpose programs designed to assist low-income electricity customers and promote energy efficiency, renewable energy, and research and development (discussed in Section 6);
- the use of performance-based regulatory approaches in place of traditional cost-of-service regulation in areas remaining under monopoly regulation, namely transmission and distribution; and

- a gradual phase-in of retail competition and direct access beginning in 1996 and ending in 2002.

The CPUC made clear in the Blue Book that what was being proposed was retail competition for generation service only. "Transmission and distribution services," wrote the Commission, "as well as system control and coordination services, will continue to receive regulatory oversight" (CPUC 1994 p.31). The regulation and general pricing guidelines for transmission and distribution services are discussed further in Sections 4 and 5, respectively.

The primary purpose of the Blue Book was to elicit comment on the CPUC's proposals. After taking comment, the CPUC issued its decision on the introduction of retail competition in December 1995 (CPUC 1995). The primary difference between the Blue Book and the CPUC's final decision was the CPUC's full adoption of a dual bilateral and "poolco" system: the decision established a structure that would give consumers the option of conducting bilateral trades, pool-based trades, or both (Bushnell and Oren 1997).

To create this hybrid structure, the decision called for the creation of two new entities, a Power Exchange (PX) designed to serve as a clearinghouse or spot market for supply and demand bidding, and an independent system operator (ISO) charged with managing grid operations (CPUC 1995, Bushnell and Oren 1997). While the CPUC's decision established the structure for the new California market, it quickly became clear that the scope of the changes envisioned in the decision was greater than the CPUC could mandate on its own. Implementing retail competition in California would require legislative action on the part of the California State Assembly and Senate.

2.2.2. Legislative Activity and *AB 1890*

After a series of hearings and debates, the California State Legislature endorsed the CPUC's proposed market structure with the passage of Assembly Bill 1890 (AB 1890) in August 1996. Signed by the Governor on September 23, 1996, AB 1890 provides the legal basis for competition for electricity service in California. In brief, AB 1890:

- calls for the establishment of a PX and an ISO as independent, public benefit, non-profit market institutions to be overseen by a five-member Oversight Board;
- requires California's IOUs to commit control of their transmission facilities to the ISO;
- allows for direct, bilateral electricity trading;
- calls for a transition to retail competition beginning January 1, 1998 and to be completed no later than March 31, 2002;
- calls for a cumulative 20% rate reduction by 2002 (beginning at 10% in 1998) over 1996 rates for residential and small commercial customers with financing for the reduction to be "securitized" by the

issuance of non-recourse state bonds designed to allow the consolidation of specific utility obligations at lower interest rates and to be repaid by all residential customers via a non-bypassable charge;

- permits up to 100% of utility stranded costs to be recovered by a non-bypassable CTC, provided it can be collected under the rate cap during the transition period;
- establishes a separate charge to pay for public purpose programs designed to support low income ratepayer assistance on an ongoing basis, and to support energy efficiency activities, research and development, and renewable energy during the transition period;
- encourages the divestiture of generation assets by the state's two largest IOUs (PG&E and SCE) to mitigate the abuse of market power;
- encourages, but does not require, public utilities to offer direct access, but does require public utilities to offer reciprocity if seeking to sell power into new retail markets in California; and
- establishes functional separation of generation, transmission, and distribution, and rules for unregulated utility affiliates.

To implement AB 1890, the CPUC was given authority to issue clarifying orders detailing the rules and procedures required to initiate competition in California. Key among these decisions was the CPUC's determination that it would be possible to allow all IOU customers access to the new market simultaneously on January 1, 1998, and that no multi-year phase-in would be required (CPUC 1997a). The CPUC also ruled that competition should be allowed in the provision of metering and billing services (CPUC 1997b).

Just weeks before the scheduled January 1, 1998 market start date the CPUC was forced to issue a ruling postponing the opening of the market due to difficulties associated with installing and testing new computer systems. As a consequence of this delay, California's competitive market for electricity opened three months late on March 31, 1998. On that date all retail customers served by the state's three major IOUs became eligible to take service from new power providers. Approximately two years later, during the summer of 2000, the state's experience with electricity sector reform degraded into crisis and its electricity restructuring process was proclaimed a failure.

Table 6.6 reviews the chronology of key legislation and regulatory decisions discussed in this section. In the next four sections we discuss in more detail the implementation of AB 1890 and the specifics of the new market design and structure, before turning in the final section to early experience with electricity reform and the crisis that ensued.

Table 6.6. Chronology of Key Legislative and Regulatory Developments

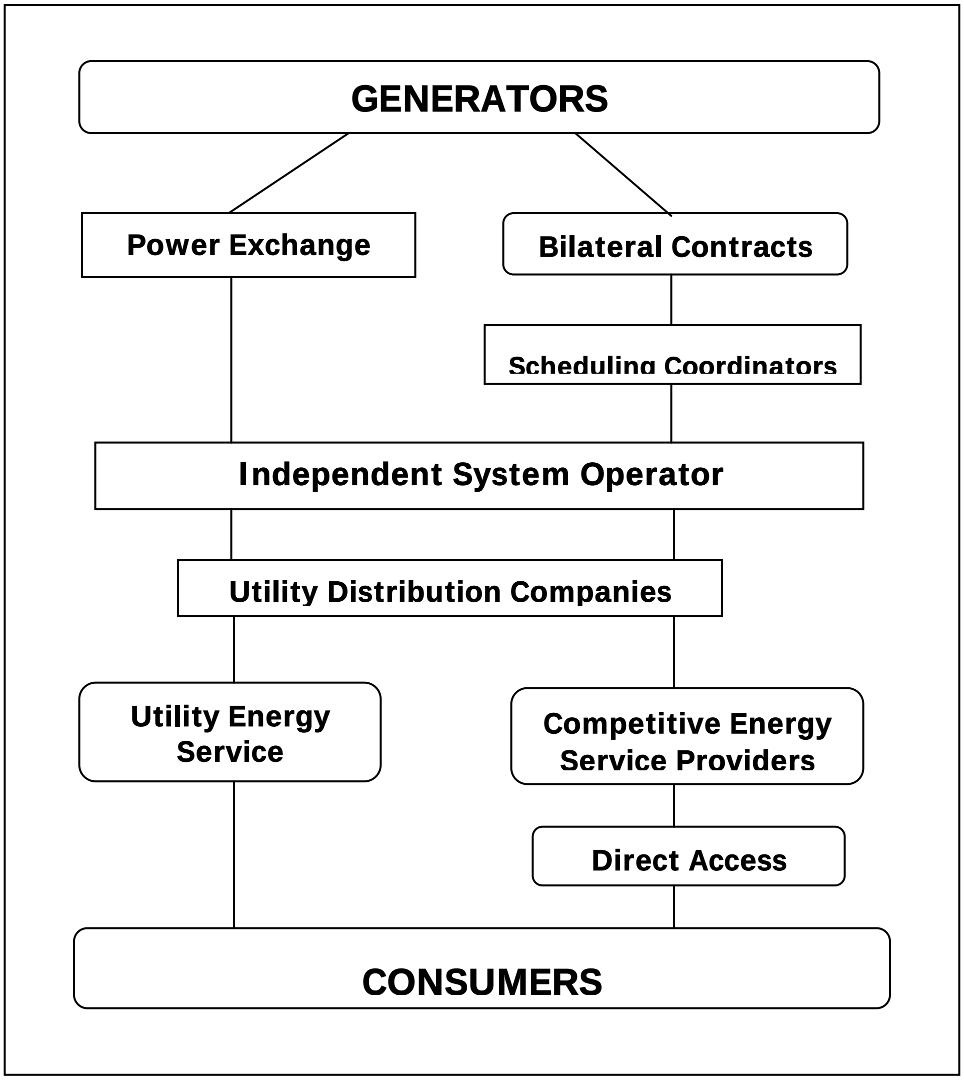
Date	Legislation, Ruling, or Event	Significance

1935	PUHCA passed	Interstate holdings restricted, monopoly service territories required, wholesale market restricted to utilities only, wholesale trading regulated by FPC (later FERC).
1978	PURPA passed	QFs established; utilities compelled to purchase QF energy.
1992	EPAct passed	EWGs established; non-discriminatory transmission access required.
1993	CPUC "Yellow Paper"	CPUC investigates possibility of instituting retail competition.
1994	CPUC "Blue Book"	CPUC proposal for introduction of retail competition in California.
1995 (March)	FERC issues "Mega-NOPR"	FERC's initial proposal for uniform open access transmission rules and stranded cost recovery.
1995 (December)	CPUC issues D.95-12-063	CPUC's decision calling for the introduction of competition in California's IOU operated electricity market via a hybrid pool and bilateral system.
1996 (April)	FERC issues Orders 888 & 889	Orders require utilities to file and use open access transmission tariffs; allows for wholesale stranded cost recovery; calls for creation of an open access same-time information system (OASIS) for electricity trading.
1996 (August)	AB 1890 passed and subsequently signed into law	California law formally mandating competition for the state's IOUs and establishing the terms for full competition statewide.
1997	AB 1890 implementation rulings	In accordance with AB 1890 CPUC issues rulings spelling out procedures for instituting competition; eliminates customer phase-in; extends competition to meter and billing services.
1998 (March)	California market opens March 31	After a three-month delay caused by computer glitches, California's new electricity market formally opens.
Summer 2000	Electricity crisis begins	The beginnings of the electricity crisis: high wholesale power prices, degraded electricity reliability, and financial losses for the state electric utilities

3. The Wholesale Electricity Market and Institutions in California

The roles and relationship between key players on both the wholesale and retail sides of the new California electricity market are illustrated in Figure 6.1. In this section we discuss the wholesale side of the market. In particular, we discuss two key institutions (and several related players) that were created by AB 1890 to facilitate wholesale electricity trading in the new California market: (1) a wholesale spot market, the California Power Exchange (PX), and (2) the new grid operator, the California Independent System Operator (ISO). We note in advance that one of these institutions, the PX, ceased operations in early 2001 as a result of the electricity crisis.

Figure 6.1. California Market Structure



3.1. The Power Exchange (PX)

Located in Alhambra, California, the California PX was created as a non-profit corporation whose primary purpose was to provide an efficient, short-term competitive energy market that met the loads of PX customers at market prices. When created, the PX was one of a potentially unlimited number of scheduling coordinators authorized to submit balanced schedules and other information to the ISO, which would then conduct real-time dispatch. The PX was operational from the beginning of 1998 through 2000, at which point it ceased operations as a result of fallout from California's deepening electricity crisis. During its period of operation, however, the PX was the most significant player in wholesale electricity trade in the state.

Key features of the PX include the following (see California Power Exchange 1998).

- The PX was open on a nondiscriminatory basis to all suppliers and purchasers.
- The PX calculated the price of electricity on an hourly basis for the day-ahead and hour-ahead (later day-of) markets, according to the demand and supply bids submitted by PX participants.
- PG&E, SCE and SDG&E—which together represent approximately 70% of the electricity sold in California—were initially required to buy all their electricity from and sell all their generation through the PX. This requirement, which has been implicated as a significant cause of the electricity crisis, was eliminated in 2001.

To participate in the PX market, a prospective participant was required to meet a number of eligibility requirements, including credit worthiness, identifying metered entities served, etc. Once certified, a participant was allowed to trade in the 24 hourly periods for next day delivery in the day-ahead market and in the single hour-period for the hour-ahead (and subsequently day-of) market. Each trade incurred a mutual obligation for payment between the PX and its market participants (Moore and Anderson 1997). We touch on the operations of these two markets here, also briefly describing the "block-forward" market developed by the power exchange.

3.1.1. The Day-Ahead Market

Procedures for trading in the day-ahead market were as follows (see California Power Exchange 1998, Moore and Anderson 1997).

- For each hour of the 24-hour scheduling day, participants submitted supply/demand bids to the PX.
- Once the bids were received, the PX validated the bids. Validation consisted of (1) verifying that the content of the bid complied with the requirements of the bid format and (2) checking for consistency with data contained in the master file.
- Once the bids were validated, the PX constructed aggregate supply/demand curves from all the bids to determine a market-clearing price (MCP) for each hour of the 24-hour scheduling day. The MCP was set at the intersection of demand and supply.
- The PX also determined if the submitted bids could create a potential over-generation condition. If a potential over-generation condition occurred, the PX was required to inform the ISO. The PX had particular rules to follow to resolve over-generation when it occurred.

- Bids initially submitted into the day-ahead market auction did not have to be attributed to any particular unit or physical scheduling plant. Such a bid is referred to as a portfolio bid.
- Portfolio bids that were accepted into the day-ahead market were then broken down into generation-unit schedules that were submitted to the ISO along with adjustment bids (to relieve congestion) and ancillary service bids.
- The ISO then determined, based on all unit-specific supply bids and location-specific demand bids, whether there was congestion. If there was congestion, the ISO uses adjustment bids to submit an adjusted schedule to the PX and other scheduling coordinators.
- These adjusted schedules and ISO determined usage charges became the foundation for zonal MCPs (discussed below) and the final schedule submitted to the ISO.
- Schedules could be comprised of imports, exports, transfers, or generation. Generator schedules were modified to compensate for transmission losses.

3.1.2. The Hour-Ahead/Day-Of Market

This market originally began as an "hour-ahead" market but was reconfigured in January 1999 to a "day-of" market to accommodate market participants. In the original hour-ahead market, bids were submitted to the PX at least 2 hours before the hour of operation. These were unit specific bids; portfolio bids were not allowed. The purpose of this market was to give participants an opportunity to make adjustments based on their day-ahead schedules so that they could minimize real-time imbalances. The MCP was determined the same way as the day-ahead market. The PX communicated price and traded quantities to PX participants immediately after the hour-ahead market was closed. Due to the lack of activity in the hour-ahead market, however, the PX introduced the day-of market. The day-of market was similar in some respects to the earlier hour-ahead market, but conducted its 24 hourly auctions during three auction periods at 6 a.m., noon, and 4 p.m. Auction period prices became available throughout the day.

3.1.3. Block Forwards Market

The California PX also developed a "block forwards" market intended to offer price hedging services. The block forwards market offered participants standardized contracts for on-peak energy on a forward month basis. Each contract was based on a specific future month at a certain quantity for the 16-hour on-peak period, from 6 a.m. to 10 p.m., excluding Sundays and designated holidays. Trading was conducted between 6-10 a.m. weekdays and prices were posted publicly at 1 p.m. on trading days. Electricity was required to be delivered to a certain California point. Essentially, the block forward market was a means for market participants to hedge against price volatility in day-ahead trading (California Power Exchange 1999).

3.2. The Independent System Operator (ISO)

Located in Folsom, California, and charged with ensuring open access and maintaining the reliability of the transmission grid, the ISO (1) coordinates day-ahead and hour-ahead schedules from all schedule coordinators and determines what adjustments need to be made to relieve congestion, (2) buys and provides ancillary services as required, (3) controls the dispatch of generation, and (4) performs real time balancing of load and generation. We touch briefly on these tasks, beginning with congestion management.

3.2.1. Congestion Management

Transmission congestion is managed by the ISO and is priced based on marginal-cost, locational pricing through zonal transmission usage charges (Bushnell and Oren 1997, Moore and Anderson 1997, Shirmohammadi and Gribik 1998). Rather than detail the ISO's congestion management role here, we have included a discussion of congestion issues in the following section that covers transmission pricing generally.

3.2.2. Ancillary Services

In its role of ensuring transmission reliability, the ISO oversees an ancillary services market, as well as scheduling ancillary services that have been self-provided by scheduling coordinators. Ancillary services acquired by the ISO include automatic generation control, spinning reserve, non-spinning reserve, replacement reserve, reactive power, and black start generation. (This last service is also known as “startup service” and consists of generating units that can provide energy to the network without any feed from outside of the plants.) The ISO holds hourly auctions for the first four services listed above, and purchases reactive power and black-start generation under long-term contracts. (Currently, these services are provided by generating plants with Reliability Must Run contracts.)

Considerable attention has been paid to the operational experience and problems encountered by the ancillary services market to date (see Gómez *et al*. 1999). While the auction process is designed to be competitive, due to a lack of bidders, the ISO has been required to impose price caps to prevent market participants from using their market power to increase prices (Wolak *et al.* 1998).

3.2.3. The Real Time Market

When it comes time to conduct actual dispatch, the ISO utilizes a real time market to adjust power generation to match actual load in real time. This process is conducted using bids for supplemental energy (i.e., capacity that has not been scheduled previously) and the generating units providing ancillary services. The ISO sorts the bids in price merit order and calls upon the bids when it is necessary to adjust the balance between generation and load. The last unit called upon in each ten-minute trading period defines the equilibrium price in the real time market.

Real time imbalances result when there are differences between scheduled and metered values for demand and supply. When meter data are processed, the imbalance for each hour and zone is calculated as the difference between the participant's use of power resources (generation and purchase contacts) and power commitments (sale contracts and consumption). Participants are charged for the difference between actual and scheduled load based on the price in the real time market.

Though this market was intended to only address small imbalances between supply and demand in real time, with the PX defunct, a considerable amount of electricity trade has taken place in this real time market.

3.3. Bilateral Trading

It is important to remember that since the inception of retail competition in 1998, wholesale electricity trading in California could be conducted either in the PX or as bilateral agreements (or through the ISO in the real time market). In either case, however, trades must be scheduled with the ISO. As such, the chief difference between bilateral and PX trading, as far as the ISO is concerned, lies in which scheduling coordinator provides the required scheduling information. As with the PX, independent scheduling coordinators facilitating bilateral trades must provide the ISO with balanced schedules and settlement ready meter data. Independent scheduling coordinators may aggregate supply and demand bids and effectively compete with the PX.

In addition, as in other wholesale electricity markets, buyers and sellers have the option of engaging in financial rather than, or in addition to, physical trades. Though we do not discuss these types of agreements in any detail here, financial arrangements can and do take the form of exchange based futures and options contracts and/or non-exchange forward agreements, including contracts-for-differences (CFDs). The New York Mercantile Exchange (NYMEX) has offered a number of futures and options contracts for delivery at the California-Oregon border, the Palo Verde interchange (located in southeast California), as well as other locations. For a review of these and other financial instruments used to hedge risk in wholesale electricity trading, see Stoft *et al.* (1998).

4. Transmission Access, Pricing, and Investment

Before the development of retail competition in California, a limited amount wholesale competition for electricity generation existed. Within this system, open, non-discriminatory access to the transmission system was required by EPAct and the FERC, as discussed in Section 2. Transmission charges were typically imposed on generators by each electric utility via capacity-based, firm, take-or-pay contracts. Each of the three major IOUs in California was responsible for the reliable operation of their transmission systems. Transmission congestion was managed internally by each utility and through coordination among the various utilities. Explicit congestion charges were not collected, although redispatch costs were effectively included in tariffs. Transmission investment and planning was managed by individual utilities and regional transmission groups, and overseen by state and federal utility regulators.

The implementation of electricity restructuring in California required new structures for transmission access, pricing, investment, and regulation, much of which was developed through a process of negotiation and compromise. The structure itself emerged from the CPUC's December 1995 decision, the state's restructuring legislation (AB 1890), the subsequent FERC filings by the IOUs (WEPEX 1996, ISO/PX 1997), and the ISO operating agreement and tariff (ISO 1998).

Under restructuring, the ISO has responsibility for operating the transmission grid of the three large IOUs and, if necessary, rationing access to congested paths. Transmission access is provided by the ISO on a non-discriminatory basis to all parties. The IOUs, however, were to continue to own the transmission assets, and earn a regulated rate of return on those assets. (Note that transmission ownership appears likely to change as a result of the electricity crisis, with the state government purchasing transmission from at least a subset of the IOUs). As described by Bushnell and Oren (1997), there are three types of transmission charges in California:

(1) transmission access charges, which are intended to recover the sunk costs of transmission investment;
(2) congestion charges, which are supposed to reflect the operational costs of transmission congestion; and
(3) loss compensation, which is also intended to reflect the operational costs of using the grid.

4.1. Access Charges

The access charges, or network tariffs, are designed to recover the full revenue requirements (i.e., the full network costs, primarily sunk investment costs) of the transmission facilities transferred to the ISO's operational control by each transmission owner (primarily the three IOUs, though publicly-owned utilities may also join). The access charges are charged to all end-use customers withdrawing energy from the ISO controlled grid, and are designed as a single, rolled-in rate that is uniform for similar customers in each utility's service area.

Actual rates and allocation methods were, at least initially, established by the CPUC for the major IOUs. Though it has been controversial, primarily due to free-rider concerns (i.e., the concern that the charges place an unfair burden on those utilities and customers that do not heavily rely on the transmission system), a major attraction of this form of cost allocation is the minimization of cost shifting both across utilities and between customers of each existing utility. To help overcome the free-rider problem, utilities found to be "dependent" on the transmission assets of another utility are responsible for paying some of the revenue-requirement of that utility's transmission assets.

4.2. Transmission Congestion Charges

Transmission congestion occurs whenever power deliveries are limited by the size or availability of transmission resources needed to serve load. The purpose of congestion management, then, is to allocate the use of, and determine the marginal value of constrained transmission lines. In its pure form, to alleviate congestion, locational prices should be defined at every bus of the network through "nodal" pricing (Schweppe *et al.* 1988).

In an effort to simplify this approach, buses in California are combined into pricing "zones," where a zone is defined as a portion of the ISO controlled grid within which congestion is expected to occur infrequently and within which every bus will therefore have the same locational price. Four zones have been defined in California – Northern California, Southern California, San Francisco, and Humboldt Counties. Through April 2001, only two of these zones have been active: Northern California and Southern California. That is, the ISO has only calculated congestion charges between these two zones.

Though the ISO has ultimate responsibility for congestion management on the ISO-controlled grid, the PX and other scheduling coordinators have been the "market makers." One controversial aspect of separating these two responsibilities was the extent to which the ISO, an entity that is not supposed to be involved in commercial decisions, could use economic criteria to ration transmission resources (in a nodal pricing, pool-based system, the pool would have unlimited use of economic criteria to manage congestion). Though the ISO in California is allowed to use some economic criteria (specifically, "adjustment bids" submitted by the scheduling coordinators from their specified "preferred schedule"), there has been concern raised that restrictions placed on the ISO may not result in least-cost congestion management (Stoft 1996). The resulting dispatch and prices may be less efficient than if the ISO was able to adjust all resources in an economic manner.

In practice, to manage inter-zonal congestion in the day-ahead market, the ISO combines the preferred schedules from all scheduling coordinators to assess the feasibility of the combined schedule in terms of coverage of losses, ancillary service requirements, reserve requirements, security criteria, and transmission capacity. When the aggregated schedule results in a congested interface between zones, the ISO uses the "adjustment bids" to adjust schedules in the zones at the two ends of each path and to determine the final day-ahead schedule and zonal prices in a way that minimizes total congestion costs. The zonal price differences, reflecting the use of adjustment bids, will then be charged to all scheduling coordinators (including the PX, during its existence) as a transmission usage charge applied to all inter-zonal transmission flows.

In the hour-ahead market, if the combined schedules result in inter-zonal congestion, then the ISO will again make the necessary scheduling adjustments to relieve congestion. The resultant hour-ahead transmission usage charges are only applied to the difference between the inter-zonal flows in the day-ahead schedule and the actual real-time inter-zonal flow. Finally, if inter-zonal constraints appear in real time, the ISO may use its ancillary service generation or the final hour-ahead adjustment bids from scheduling coordinators to manage the constraint.

The main use of the zones is in determining the transmission usage charge across zones and in establishing locational differentiation of power prices when inter-zonal congestion exists. The transmission usage charge is effectively a congestion charge collected by the ISO from the scheduling coordinators (including the PX), and is defined as the difference in zonal prices that is applied to the flow along the congested inter-ties linking the congestion zones. Scheduling coordinators with schedules that relieve congestion on a congested interface receive a credit equivalent to the difference in zonal prices. Revenues collected from the transmission usage charge are credited against the revenue requirements of the various electric utilities and therefore reduce access charges.

Thus far, the mechanics of inter-zonal congestion management and pricing have been described. It is also possible, however, for congestion to occur within a zone. If congestion occurs *within* a particular zone (intra-zonal congestion), the ISO uses adjustment bids to alleviate the congestion at minimum cost, and a zone-by-zone grid operations charge is imposed to collect the costs of using the adjustment bids from all transmission users based on their consumption.

In April 1999, the ISO approved the formation of firm transmission rights (FTR). An FTR is a contractual right that entitles the holder to receive a portion of the usage charges collected by the ISO when inter-zonal congestion exists. FTRs allow the market participant who holds the interface rights to collect congestion charges whether or not it transmits power through that interface. The ISO conducts an annual FTR clearing price auction for each FTR market corresponding to different transmission paths from an originating zone to a receiving zone. FTRs allow market participants to hedge price risk associated with the incidence of congestion.

4.3. Transmission Losses

Each scheduling coordinator ensures that each generating unit for which it submits balanced schedules provides sufficient energy to meet both its demand and its estimated marginal contribution to transmission losses. Scheduling coordinators can self-provide transmission losses by submitting a balanced schedule that includes the appropriate quantity of transmission losses, or can settle obligations to provide transmission losses with the ISO using the real-time imbalance energy market.

Transmission loss responsibilities are determined through the use of a power flow model, which calculates a "generation meter multiplier" for each generator location. These multipliers can, in turn, be used to calculate the total demand that can be served by a given generating unit in a given hour, taking account of transmission losses.

4.4. Investment and Planning

Transmission planning and investment decisions for those utilities participating in the ISO were intended to be coordinated by the ISO, with participation from regional transmission planning organizations. The ISO, a participating utility, or any other market participant could determine the need for and propose to the ISO a transmission system addition or upgrade if it would promote economic efficiency or maintain system reliability. The ISO was expected, in cooperation with regional transmission organizations and state and federal regulators, to determine when and where new transmission investment is required and to assign the costs to the various beneficiaries of the addition or upgrade in proportion to their net benefits. The utilities would then be required to make the necessary investments, the costs for which would be recovered from benefiting market participants and/or via the access charges. FERC may also require transmission investments. As a practical matter, however, it is important to note that through mid 2001, very few transmission investments have taken place since California's market opened for competition. Further, we note that transmission planning and investment processes may change significantly if the state of California purchases the transmission assets of certain IOUs, as expected under the deepening electricity crisis in the state.

5. Distribution Network Regulation and Retail Competition

While industry restructuring in California required the IOUs to turn over transmission control functions to the ISO, the IOUs retained control over the distribution network, which remains regulated by the

CPUC. Shorn of their transmission and generation control functions, these restructured "wires" utilities are now referred to as utility distribution companies (UDCs). In this section we discuss the role and regulation of UDCs and the distribution services they provide, as well as their relationships with the competitive energy service providers (ESPs) that were allowed to compete for customers in California beginning in 1998.

5.1. Regulation of the Distribution Network

As noted earlier, the distinction between interstate and intrastate commerce in the US forms the dividing line between federal (interstate) and state (intrastate) regulatory control. For a fluid commodity like electricity the distinction between interstate and intrastate has, in general terms, been simplified into a distinction between wholesale and retail transactions, with the federal government overseeing wholesale electricity trading and the states overseeing retail transactions. As a consequence of this distinction, state regulators in the US have typically overseen utility distribution networks on the grounds that these are more closely related to end-use (i.e., retail) electricity consumption.

With the advent of competition, however, the precise dividing line between transmission and distribution systems has become more important. The FERC sought to clarify the distinction between federal and state authority in Order 888 by articulating seven criteria that distinguish local distribution facilities from interstate transmission facilities. These criteria form the basic dividing line between state and federal control in the US and are as follows.

1. Local distribution facilities are normally in close proximity to retail customers.
2. Local distribution facilities are primarily radial in character.
3. Power flows into local distribution networks; it rarely flows out.
4. When power enters a local distribution system, it is not recognized or transported on to some other market.
5. Power entering a local distribution system is consumed in a comparatively restricted geographical area.
6. Meters are based at the transmission/distribution interface to measure flows into the local distribution system.
7. Local distribution systems are reduced voltage systems.

The CPUC regulates distribution services based on this distinction. Under AB 1890 distribution services are provided on a regulated monopoly basis by the UDC, which is also responsible for maintaining the distribution system and responding to outages and other emergencies.

5.2. Remuneration for Regulated Distribution Activities

Historically, distribution revenue-requirements have been established through cost-of-service, rate-of-return regulation and formal rate cases before the CPUC. Under this approach, the price of distribution service charged by a utility includes all of its variable and fixed costs plus a reasonable return on invested capital.

More recently, however, the major electric utilities in California have been placed under performance-based ratemaking (PBR), which decouples utility profits from costs and, instead, ties profits to performance incentives. This decoupling is accomplished by decreasing the frequency of rate cases, employing external measures of cost for the purpose of setting rates, or a combination of the two (Comnes *et al.* 1995). These systems are intended to reward performance and therefore result in greater productivity and lower costs over time, and to reduce the frequency of complex and costly ratemaking procedures. In practice, there are different types of performance-based regulation, including price caps, revenue caps, sliding scale, and targeted incentive regulation.

Although the use of and benefit from performance-based ratemaking was articulated and reaffirmed throughout the state's restructuring process (beginning in 1994), PG&E, SCE, and SDG&E had filed initial PBR plans in 1992 and 1993 (EIA 1998a). The PBR plans ultimately adopted by the CPUC for each of these three utilities differ, sometimes significantly (SDG&E has a revenue cap, whereas SCE and PG&E use a price cap), and the distribution PBR mechanisms are still being refined. Despite differences, a CPUC study points out that the plans all include (see CPUC 1997c):

- a formula to establish revenue requirements or rates that are indexed to inflation and adjusted for productivity changes and that are adjusted to account for changes in the cost of capital;
- a revenue-sharing mechanism allowing shareholders and ratepayers to share actual revenues compared to those authorized;
- a reward/penalty system to ensure that employee safety, reliability, and customer satisfaction standards are maintained compared to established benchmarks;
- inclusion of adjustments, "Z" factors, to capture the influence of exogenous factors not under the utility's control; and
- a monitoring and evaluation program.

Another aspect of remuneration for distribution activities stems from the potential for distribution system line losses (as well as losses associated with meter error and energy theft). To account for these energy losses, customer class specific "distribution loss factors" are calculated by the three major IOUs, and are used for scheduling and settlement purposes (Distribution Loss Factors Working Group 1998).

5.3. Retail Competition

As noted earlier, under AB 1890 and related CPUC rulings, all retail customers in California's IOU service territories were given the opportunity to choose to have their electricity and their meter and billing services provided by an independent energy service provider (ESP) beginning in 1998. But Californians were not compelled to switch power providers, and could opt to continue to have their power and meter/billing needs met by their UDC, subject to the legislatively mandated 10% rate reduction discussed previously. Regardless of who supplies customers with their electricity, however, all customers must pay their local UDC's transmission and distribution fees, as well as the CTC and similarly non-bypassable public purpose fees.

Those customers who did opt to switch power providers could conduct business with one of several unregulated ESPs. These entities are unregulated in as much as they are not subject to the type of monopoly regulation that UDCs are subject to. But it is important to note that ESPs must meet certain criteria to participate in the market and their behavior is subject to review by the CPUC, the Federal Trade Commission (FTC), and other consumer protection bodies. Below we review the role of ESPs and related entities offering both energy and meter and billing services.

5.3.1. ESPs and Competitively Offered Energy Services

To offer services in the retail market ESPs must first enter into an UDC-ESP service agreement that, at a minimum, includes:

- ESP identification and contact information;
- a warranty that the ESP has obtained a certified scheduling coordinator; and
- an agreement on the provision of meter and billing services including data protocols for the exchange of meter and billing data.

In addition, if the ESP is seeking to serve residential or small commercial customers (defined as customers with less than a 20 kW demand) AB 1890 required that the ESP: (1) register with the CPUC (providing contact information, legal details and history, and evidence of firm power supply contracts and/or sources), and (2) employ an authorized independent verification agent (IVA) who will contact and independently verify the decision of customers under 20kW seeking to switch suppliers. The purpose of the IVA was to protect small customers from unscrupulous or high-pressure sales tactics.

Once these steps had been taken, the ESP could begin submitting Direct Access Service Requests (DASRs) to the UDC. ESPs must submit a DASR for each new customer with direct access service. DASRs must generally include customer name, service account address, UDC service account number, ESP name, ESP registration number (if applicable), metering service option and equipment needs (if applicable), meter identification information (if not UDC meter), and billing service option. Once the DASR has been processed, the customer account is switched and the customer begins taking service from his or her new ESP. In the event the ESP is unable to meet its energy or financial commitments, the ESP's customers will default to the UDC.

5.3.2. Billing and Metering Services

The CPUC determined before the implementation of retail competition that ESPs and related entities should be free to compete with UDCs in offering meter and billing services as well as power supply (CPUC 1997a, CPUC 1997b). Under the CPUC's rulings on meter and billing services, ESPs could offer three billing options:

(1) consolidated UDC billing, in which both ESP and UDC charges are billed by the UDC;
(2) separate billing, in which the ESP and UDC send separate bills for their respective services, or
(3) consolidated ESP billing, in which both ESP and UDC charges are billed by the ESP.

In the area of metering, the CPUC determined that ESPs may provide metering services subject to specific requirements. The ESPs and/or UDCs providing metering services are ultimately responsible for collecting, transferring, and processing meter data, but the actual provision of meters and the collection of meter data is carried out by meter service providers (MSPs), who must be state certified, and meter data management agents (MDMAs), who are screened by the UDCs. These two entities engage in the installation of meters and the management of meter data, respectively. Typically these entities are specialized companies whose services are contracted for by the UDCs and/or ESPs. While competition is allowed in the provision of meters and in meter reading technology, all metering entities must abide by open architecture standards at specific points in the meter data flow network (CPUC 1997d). These open architecture standards are designed to ensure that incompatible and/or entirely proprietary metering systems do not develop.

6. Particular Aspects of the Regulatory Process in California

6.1. Stranded Costs

One of the most contentious parts of the electricity restructuring process in California has been the recovery of so called “stranded costs.” Under the historic cost-of-service, rate-of-return form of regulation, the CPUC allowed revenues to be collected by the utilities for those costs prudently incurred to serve customers, including a reasonable profit on and repayment of their capital investments. In a competitive marketplace, revenues received will be set by the marketplace, not regulators, and such revenue may not be sufficient to provide utility shareholders a return on their original investment. Roughly speaking, then, “stranded costs” are simply the difference between regulated retail electricity prices for generation services and the competitive market price of power.

The level of total stranded costs in California depends on the market price of electricity. At the onset of electricity restructuring, when PX prices were expected to average approximately 2.4 cents/kWh, SCE, PG&E, and SDG&E estimated their total stranded costs to be $26.4 billion, most of which is associated with nuclear investment and above-market power purchase contracts paid to non-utility generators. With the substantially higher PX prices experienced during the first several years of market operations, however, the utilities’ total stranded costs have proven to be much lower.

Because California utilities’ past investments were made as part of the "regulatory compact" and were approved by the CPUC, the CPUC and the state legislature determined that it would be unfair to penalize utility shareholders and bondholders for these past investments. Stranded cost recovery was therefore allowed, paid by *all* customers through a separate, volumetric, cents per kWh charge on electricity bills. As noted earlier, this charge is called the “competition transition charge,” or CTC, and was to be levied on customers from 1998 through 2001. The charge is non-bypassable, and cannot therefore be avoided by switching electricity providers.

The utilities were not, however, strictly guaranteed to recover all of their stranded costs. Rather, retail electricity rates were originally fixed for the duration of the stranded cost recovery period (1998-2001). The amount of money available for stranded cost recovery was therefore equal to the difference between the retail electricity rates to final customers (capped at the 1996 level minus the 10% reduction) and the cost of meeting the demand (transmission and distribution costs plus the energy costs). If the difference between these two quantities was not sufficient to pay off all stranded costs, the utilities were required to write off the remaining amount. If on the other hand, the utilities cold collect all of their stranded costs before 2001, the rate freeze was to end. SDG&E, for example, completed their stranded cost recovery and rate freeze period in 2000, ending their rate freeze.

6.2. Market Power

The goal of electricity industry restructuring is to move from a regulated utility monopoly structure to a workably competitive marketplace. But restructuring will not be in the public interest if it allows some companies to exploit market dominance and to stifle competitive market forces. Market power is the ability of one firm, or a set of firms, to unduly influence prices, quantities, product quality, and other conditions in a particular market. In the past, because of extensive state and federal regulation, market power has not been considered a significant problem. As restructuring proceeds, however, at least three types of market power are recognized to have the possibility of distorting competition:

- **Vertical market power**, resulting from ownership or control by a single firm of more than one phase of electricity production (generation, transmission, distribution). Vertical integration and market power may allow a firm to erect barriers to entry or otherwise shift costs and revenues among affiliates in ways that distort efficient market operation.
- **Horizontal market power**, resulting from concentration of ownership or control of any single phase of electricity production, such as generation; for example, it would allow generators to withhold generation or bid strategically to force higher market-clearing prices.
- **Locational market power,** where a specific generation facility might provide unique services (e.g., reliability) needed for a particular geographic region and thus command a premium market price.

California's restructuring legislation and subsequent implementation imposed numerous requirements in an attempt to reduce the potential for abuses of market power, requirements that, as we discuss shortly, have proven inadequate in successfully mitigating market power abuses. In brief, California's legislative and regulatory bodies have:

- created an ISO to operate the utilities' transmission system and to control vertical and locational market power,
- required the mitigation of locational market power by requiring generators that are needed to solve local reliability problems to enter into Reliability Must Run (RMR) contracts with the ISO, thereby fixing the amount that a generator is paid when operated for reliability reasons (for a detailed discussion of the functioning and problems with this market, see ISO 1999a),
- called for utility divestiture of much of their generation assets in California to reduce concentration in the generation sector, and therefore horizontal market power,
- required the IOUs to temporarily bid all of their generation into the PX and also to purchase all of their electricity from the PX to further mitigate horizontal market power and self-dealing,
- called for the functional unbundling of generation, transmission, and distribution,
- established affiliate rules that do not allow affiliated, unregulated companies of the regulated utilities to unduly use their market position to restrict competition, and
- established price caps on various of the ISO's markets.

6.3. Public Purpose Programs

Under AB 1890, public funding mechanisms were established to continue to support a range of activities that fall under the loose heading of public purpose programs. These programs include activities designed to support or promote (1) low-income customer assistance, (2) energy efficiency, (3) renewable energy, and (4) research, development, and demonstration (RD&D) activities. These programs were historically mandated by the CPUC and the state legislature and administered by the utilities themselves, subject to regulatory oversight. This arrangement allowed the costs incurred by utilities in facilitating or providing public purpose programs to be recovered as part of their regulated monopoly ratebase.

Concerned that the important public benefits these programs provide would be lost in the new market structure, the legislature mandated that funding for public purpose programs come from a non-bypassable charge on consumers' bills. Specifically, AB 1890 specifies that monies be collected and used as follows.

- Low-income customer assistance is to continue indefinitely, funded at no less than 1996 levels (roughly $324 million).
- Energy-efficiency programs are to be supported from a fund of $872 million to be collected from 1998-2001.
- Renewable energy technologies are to receive assistance from a fund of $540 million to be collected from 1998-2001.
- Research, development, and demonstration programs are to be supported from a fund of $250 million collected from 1998-2001.

Under AB 1890, the CPUC was given control over of the low income and energy efficiency funds, and the CEC control over the renewable energy and RD&D funds. Illustrating the importance of these public purpose programs, in the year 2000 legislation was passed to extend funding for these programs through 2012 at similar yearly funding levels as those established for the initial 4-year transition period.

6.4. Customer Protection and Small Customer Interests

Finally, under AB 1890 it was deemed important to address potential equity and distributional implications of electricity industry restructuring. At the onset of reform in California, many believed that, due to their relative lack of bargaining power, small customers (especially residential and rural customers) would not see as many benefits from restructuring as larger customers.

In California, the legislature wanted to ensure at least some benefits for smaller customers. Consequently a mandated initial 10% rate reduction from 1996 rates took place in January 1998 for residential and small commercial (i.e., less that 20 kW) customers. Based on the legislation, rates were to be reduced by a further 10% in 2001. As noted earlier, to help finance the rate reduction, AB 1890 authorized the IOUs to issue "rate reduction" bonds, the proceeds of which would be used to help pay-off a portion of the utilities' stranded costs. Because the bonds carry a lower interest rate and a longer term than otherwise would have been feasible, they allowed an immediate 10% rate reduction.

In addition to a guaranteed rate cut, AB 1890 also mandated supplier price and fuel source disclosure requirements, registration requirements, and the continuation of the universal service requirement, which ensures that UDCs will continue to serve all customers seeking service in their historic service territory. The CPUC also put in place affiliate transaction standards. These standards were designed to prevent the incumbent utility from abusing its position as the distribution company to encourage customers to take service from its unregulated subsidiary.

7. Market Operations experience and the Energy Crisis

This section presents early market operations experience with California's restructured electricity sector, and highlights the nature, causes, and solutions to the state's energy crisis. Text for this section is being written in April 2001, in the midst of the crisis itself. Because California's electricity sector is in such flux, with new market, regulatory, and legislative events occurring on a daily basis, we keep this section brief and simply summarize the key points. The reader is referred to other documents for more in-depth and updated analyses of experience with California electricity reform and the ensuing crisis (see, e.g., World Bank 2001, Borenstein 2001, Marcus and Hamrin 2001, Joskow and Kahn 2000, McCullough 2001).

7.1. Market Operations: 1998 and 1999

During the first two years after market reform in 1998, there was limited evidence of the problems that would consume California's electricity sector beginning in the summer of 2000. But even during these first two years of market operations, some problems were evident. First, market power was detected on the part of electric generators, who were apparently able to raise prices above competitive levels (Borenstein, Bushnell and Wolak 1999). Second, the ISO's ancillary services markets were being constantly re-designed in the face of bid insufficiency, considerable price volatility, and the apparent exercise of market power by generators, prompting the ISO to institute price caps (Siddiqui *et al.* 2000, ISO 1999b). Finally, customer switching to competitive energy service providers remained low during these early years of reform. At its peak, just over 10% of eligible load had switched providers in California: 16% of eligible industrial customers switched providers, for example, as did approximately 2% of residential customers. (For reviews of ESP product offerings, customer switching, and customer switching experience, see Wiser, Golove, and Pickle 1998, and Golove *et al.* 2000).

Despite these concerns, however, few emergencies were called, reliability remained relatively high, and market prices were low overall. From 1 August 1998 to 30 June 2000, 99% of the energy traded in the PX was in the day-ahead market. During the same period, the total amount of energy traded in the PX was equal to 370 TWh, with prices averaging $33.84/MWh and $37.63/MWh in the day-ahead and hour-ahead/day-of markets, respectively. The PX day-ahead and hour-ahead/day-of unconstrained markets also performed with predictable, seasonal, and daily patterns. Prices rose considerably in summer months, only to decrease during the winter period.

7.2. The Electricity Crisis

Beginning in the summer of 2000, and without a great deal forewarning, California's electricity system plunged into crisis. The full effects of this crisis can be seen in many different ways:

- **Wholesale Power Prices Skyrocket:** Beginning in June 2000 and continuing to the time of this writing, wholesale electricity prices rose to unprecedented levels. By way of example, the total cost of wholesale electricity procurement to meet load in the ISO's control area during 1999 was $7.4 billion. In 2000, that cost rose nearly fourfold, to $28 billion. Wholesale electricity prices, as seen in the PX day-ahead market and the ISO's real time market, have sustained price levels that easily exceed 10 cents/kWh and in some months average prices have exceeded 30 cents/kWh. Such prices, as seen on the spot market, are expected to continue for some time to come.

- **Electricity Reliability Degrades:** At the same time, electricity reliability got progressively worse. Stage 3 emergencies are the highest level of electrical emergency called by the ISO, and are triggered when operating reserves fall below 1.5%. No such emergencies were called in 1999. One Stage 3 emergency was called during 2000. In 2001, through only March, a full 36 such emergencies were called. More seriously, during the first three months of 2001, the ISO was required to call for rolling blackouts several times to match supply and demand in the state. Periodic rolling blackouts are expected to continue and worsen through the summer of 2001 and perhaps 2002.

- **Financial Catastrophe for Utilities:** Required by AB1890 to purchase power from the PX spot market to meet their electricity needs, and to sell that power at capped retail electricity rates, the in-state electric utilities were deeply in debt by the end of summer 2000, as wholesale procurement costs far outstripped retail electricity revenues. Through March 2001, an alleged $13 billion in under-collections was incurred by the in-state utilities, making these utilities unable to secure credit for further power purchases. In early 2001, the state government stepped in to purchase electricity on behalf of the utilities. On April 6, 2001, PG&E filed for bankruptcy.

- **Retail Access Dies:** With massive regulatory uncertainties and unprecedented wholesale electricity prices, competitive electricity service providers largely withdrew from the state in late 2000 and early 2001, turning customers back to the utilities for default service. Further, legislation in early 2001 suspended retail access, at least until the crisis is controlled, effectively ending California's experiment with retail choice.

7.3. The Causes of the Electricity Crisis

The causes of California's electricity crisis are several, and by no means has consensus been reached on the relative importance of various causal factors. A number of the more important causes implicated in the crisis are highlighted here:

Market Fundamentals

- **Supply-Demand Balance:** Load growth throughout the Western United States outstripped new plant construction during the 1990s, resulting in a tightening of the supply-demand balance. Average demand growth in California from 1996-2000 was 2.5% per year. Importantly, region-wide demand growth resulted in deep cuts in the electricity imports that California historically relied upon during the summer months.
- **Natural Gas Prices:** Natural gas prices, which normally range from $2 to $3/mmbtu, increased nationwide, but especially in California where pipeline capacity constraints are significant and market power abuses have been claimed. Natural gas prices peaked at $60/mmbtu in late 2000, and have consistently averaged well above the national average.
- **Emissions Credits:** Power plants located in the Los Angeles basin are required to purchase emissions credits to offset their own pollutant emissions. The cost of these emissions credits increased dramatically in the year 2000 with the increased utilization of in-basin power plants.

Market Structure

- **PX Buy-Sell Requirement:** Electric utilities, required initially to purchase their power from the PX spot market, while selling their power at capped retail electricity rates, were largely unable to enter into long-term hedging contracts to mitigate price volatility and protect against high spot market prices.
- **Generation Divestiture without Buy-Back Contracts:** Utilities divested a significant amount of their generation capacity, without long-term buy-back contracts. This exacerbated the abuse of market power by generators and offered no price stability or certainty for utility electricity purchases.
- **Retail Rate Freeze and Little Demand Response.** A competitive market generally requires responsive supply and demand. With a retail electricity rate freeze, and with the market rules established at the ISO, little economic opportunity for demand responsiveness existed.
- **Uncoordinated Maintenance Schedules.** Uncoordinated generator maintenance schedules helped contribute to a lack of supply during even winter months, when demand is generally relatively low in the state, as multiple generation units were down for maintenance simultaneously.

Market Power

- Concentration in generation plant ownership, a large amount of unhedged power purchases, limited demand response, and tight supply conditions offered electricity generators the ability to exert substantial market power. The withholding of generation capacity – either physically or economically – has been of particular concern, and numerous studies have detected abuses of market power. The abuse of market power appears to be a significant contributing factor to the high wholesale power prices.

Regulatory and Political Inaction

- **Policing Market Power.** Numerous analysts have pointed to FERC's apparent inability or unwillingness to strongly police market power abuses, through price caps or other measures, as a contributing factor to the duration of the crisis.
- **Long Term Hedging Contracts.** The CPUC and California State Legislature's inaction in quickly allowing and approving the use of long term, power-purchase hedging contracts contributed to the crisis.
- **Rate Freeze and Demand Response.** Finally, an initial unwillingness by state policymakers to end the rate freeze and raise retail electricity rates to more accurately reflect costs, thereby also stimulating demand response, deepened the financial crisis for the utilities and did nothing to ease the supply-demand imbalance.

7.4. Solutions and Conclusions

Multiple solutions to California’s electricity crisis have been proposed, though it is evident that a “quick-fix” is not likely. While many agree that regulatory and political response has been inadequate, through March 2001 responses have included:

- increased retail electricity rates,
- modest caps on wholesale electricity prices,
- elimination of the requirement that utilities sell into and purchase from the spot market,
- authorization of a state agency to purchase power of behalf of the utilities, funded in part by electricity rates and in part by state taxpayers,
- allowing that state agency to enter into long-term contracts for power to reduce price volatility,
- increased spending on energy efficiency and renewable energy programs, including the development of multiple programs intended to stimulate demand response,
- easing the siting and permitting process for new electrical generation plants in the state, and
- negotiating with the IOUs for the state to purchase the utilities’ transmission assets, thereby easing their financial problems (one such deal had been finalized by early April 2001).

California’s electricity crisis clearly resulted from a confluence of factors, many of which were nearly impossible to predict and some of which predated electricity restructuring in the state. Regardless of the causes and solutions, it is apparent that the crisis will have substantial implications for the future of competitive electricity markets not only in California but perhaps worldwide. At the very least, the problems experienced in California call for a rethinking of the design and regulation of competitive electricity markets.

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